F24
EB-2008-0223

OGILVY RENAULT

RECEIVED

MAY 04 2009

ONTARIO ENERGY BD

Direct Dial: (416) 216-4771
Direct Fax: (416) 216-3930
ataylor@ogilvyrenault.com

Toronto, April 30, 2009

OEB BOARD SECRETARY	
File No:	SubFile:
Panel	
Licensing	
Other	
00/04	

Ms. Kirsten Walli
Board Secretary
Ontario Energy Board
2300 Yonge Street
Suite 2700, PO Box 2319
Toronto, ON, M4P 1E4

Dear Ms. Walli:

RE: Canadian Niagara Power Inc. – Fort Erie
Canadian Niagara Power Inc. – Easter Ontario Power
Canadian Niagara Power Inc. – Port Colborne
EB-2008-0222, EB-2008-0223, EB-2008-0224

Please find enclosed the Undertakings of Canadian Niagara Power Inc. that were given at the oral hearing during the week of April 20, 2009.

EB-2008-0222
EB-2008-0223
EB-2008-0224

Yours very truly,

Ogilvy Renault LLP

Andrew Taylor

Ontario Energy Board

FILE No. JT1.1, JT1.2, JT1.3, JT1.4, JT1.5, JT1.6, JT1.7,
UNDERTAKING JT1.8, JT1.9, JT1.10, JT1.11,
DATE May 4, 09
JT1.12, JT1.13, JT1.14, JT2.1
08/99 JT2.2, JT2.3, JT2.4, JT2.5, JT2.6, JT3.1, JT3.2, JT3.3,

AT/rd

Encl.

cc. All Parties Listed on Intervenor List

UNDERTAKING NO. JT1.1:

To advise why directional effect is reasonable.

Response:

This question related to the reasonableness of a weather normalization adjustment factor stemming from the theoretical assumption that 100% of the distribution load was weather sensitive. Under the methodology employed in the rate applications, such a condition would yield an adjustment factor of unity and the weather correction factor would be the same as that of the IESO.

The response to this undertaking was provided orally, with discussion, following the morning break. The response begins at the bottom of page 55 and continues on to the beginning of page 63 of the transcript, EB-2008-0222-0223-0224,April20Vol1.

UNDERTAKING NO. JT1.2:

To confirm that the forecast for the 2009 Rate Year continues to be based on the assumption that there will be no Standby Service Revenues

Response:

The following is the response given to Board Staff Interrogatory # 39 related to this matter.

Below is the excerpt from Exhibit 3/Tab 3/Schedule 1/pages 1-2 Miscellaneous Service Revenues (OEB Account 4235)

Revenues generated from other specific service charges. In 2006, CNPI applied for and received approval from the Board to charge the set of standardized service charges. There are no changes to specific service charges being requested for 2009. Stand-by revenues for two co-generation customers have been allocated to this account up to and including the 2008 Bridge Year. As explained in Schedule 3, these revenues have been removed from the 2009 Test Year.

To clarify this, in the 2006 EDR, CNPI had reported revenue associated with standby distribution revenue for two customers with load displacement generation facilities. At that time in 2006, CNPI's financial recording system was not enabled to account for these revenues as electric revenue. Consequently, CNPI forecasted and reported this revenue as miscellaneous revenue. For rate making purposes the forecasted revenue from standby service was included as miscellaneous revenue and subtracted from the service revenue requirement, therefore the base revenue requirement used to develop distribution rates did not include the revenue associated with standby service.

Below is the excerpt from Exhibit 3/Tab 2/Schedule 1/pages 21/lines 29 to 31

CNPI has allocated standby distribution revenue, if any, to the Base Revenue Requirement for the General Service 50 to 4,999 kW customer class.

To further clarify, for 2009 Test Year, CNPI's financial recording system has the capability to report standby revenue as electric *distribution revenue. Therefore, it is no longer necessary to assign forecasted revenue from standby service to miscellaneous revenue and deduct that same forecast from the base revenue requirement.*

In this Application, the Miscellaneous Service Revenues (OEB Account 4235) has no association with revenue from standby service. Revenue from standby service, if any, has been forecasted in and will be reported in electric distribution revenue and is part of the base revenue requirement.

The current practice for standby charges in CNPI – Port Colborne has the standby charge per kW based upon an agreed quantity, not the capacity of the displacement generators but much less. Given the change in operating mode of the customers, the current billing demand for distribution service is consistently greater than the agreed standby quantity. With 2009 approved distribution rates, CNPI – Port Colborne would only bill standby when the billing demand is less than the agreed standby demand quantity.

Based on the operating forecast of the embedded generators, CNPI had not forecasted standby revenue for the 2009 rate year. This forecast is still valid.

UNDERTAKING NO. JT1.3:

To advise whether training costs would decrease in 2008

Response:

The question was regarding the increase in customer service training costs in CNPI – Port Colborne in IRR OEB#54 and why the following year decrease is not apparent.

The question was answered orally and can be found in the transcript on pages 128 to 130.

UNDERTAKING NO. JT1.4:

To provide 2008 values for Exhibit 4, Tab 2, schedule 8

Response:

CNPI – Fort Erie, Calculation of Loss Factors					
Description	**2006 EDR Board Approved**	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008**
Wholesale kWh - No Losses (A)		308,035,878	299,465,584	308,113,038	303,687,698
Wholesale kWh - With Losses (B)		309,059,226	300,471,450	309,102,483	304,689,868
Supply Facility Loss Factor (C=B/A)	1.0045	1.0033	1.0034	1.0032	1.0033
Three Year Average				1.0033	1.0033
Wholesale kWh - No Losses (D)		308,035,878	299,465,584	308,113,038	303,687,698
Embedded Wholesale Customers (E)		NIL	NIL	NIL	NIL
Embedded Generation – No Losses (F)		NIL	NIL	NIL	NIL
Total Supply – No Losses (G=D-E+F)		308,035,878	299,465,584	308,113,038	303,687,698
LTLT Physical Distributors (H)		(94,189)	(101,805)	(119,261)	Not Available
Effective Supplied kWh (I=G+H)		307,941,689	299,363,779	307,993,777	303,687,698
Retail kWh (J)		299,287,126	287,341,134	297,196,138	287,833,001
Unaccounted For Energy (K=I-J)		8,654,563	12,022,645	10,797,639	15,854,697
Distribution Loss Factor (L=I/J)	1.0432	1.0289	1.0418	1.0363	1.0551
Three Year Average				1.0357	1.0444
Total Loss Factor (M=C*L)	1.0479	1.0323	1.0453	1.0397	1.0478
Three Year Average				1.0391	1.0443

CNPI – Port Colborne, Calculation of Loss Factors					
Description	**2006 EDR Board Approved**	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008**
Wholesale kWh – No Losses (A)		191,990,734	199,654,090	197,952,323	205,182,466
Wholesale kWh – With Losses (B)		191,526,525	200,272,869	198,978,855	206,228,897
Supply Facility Loss Factor (C=B/A)	1.0045	0.9976	1.0031	1.0052	1.0051
2007/2008 Actual Determinant				1.0052	1.0051
Wholesale kWh – No Losses (D)		191,990,734	199,654,090	197,952,323	205,182,466
Embedded Wholesale Customers (E)		NIL	NIL	NIL	NIL
Embedded Generation – No Losses (F)		3,968,854	1,930,744	1,344,814	Included Above
Total Supply – No Losses (G=D-E+F)		195,959,588	201,584,834	199,297,137	205,182,466
LTLT Physical Distributors (H)		777,974	653,544	707,136	Not Available
Effective Supplied kWh (I=G+H)		196,737,562	202,238,378	200,004,273	205,182,466
Retail kWh (J)		201,392,408	199,276,154	193,646,076	192,894,441
Unaccounted For Energy (K=I-J)		(465,4846)	2,962,224	6,358,197	12,288,025
Distribution Loss Factor (L=I/J)	1.0276	0.9769	1.0149	1.0328	1.0637
2007 Actual & 2008 Average				1.0238	1.0371
Total Loss Factor (M=C*L)	1.0322	0.9745	1.0180	1.0382	1.0424
2007/2008 Determinant				1.0382	1.0424

The energy associated with Long Term Load transfer customers is not yet available and has been omitted from these calculations.

CNPI – Eastern Ontario Power, Determination of Loss Factors					
Description	**2006 EDR Board Approved**	**2005 Actual**	**2006 Actual**	**2007 Actual**	**2008**
Wholesale kWh - No Losses (A)		73,726,610	57,404,676	59,150,220	43,172,735
Wholesale kWh - With Losses (B)		76,233,315	59,356,435	61,161,327	44,640,608
Supply Facility Loss Factor (C=B/A)	1.0340	1.0340	1.0340	1.0340	1.034
Three Year Average				1.0340	1.034
Wholesale kWh - No Losses (D)		73,726,610	57,404,676	59,150,220	43,172,735
Embedded Wholesale Customers (E)		NIL	NIL	NIL	NIL
Embedded Generation – No Losses (F)		13,597,830	20,629,114	12,682,819	24,794,416
Total Supply – No Losses (G=D-E+F)		87,324,440	78,033,790	71,833,039	67,977,150
Effective Supply Facility Loss Factor (H=(B+F)/(A+F))		1.0287	1.0250	1.0280	1.022
Three Year Average(I)				1.0272	1.0248
LTLT Physical Distributors (J)		NIL	NIL	NIL	NIL
Effective Supplied kWh (K=G+J)		87,324,440	78,033,790	71,833,039	67,977,150
Retail kWh (L)		86,515,636	75,398,070	66,086,052	62,983,629
Unaccounted For Energy (M=K-L)		808,804	2,635,720	5,746,987	4,983,521
Distribution Loss Factor (N=K/L)	1.0363	1.0093	1.0350	1.0870	1.0791
Three Year Average				1.0438	1.0670
Total Loss Factor (M=N*H)	1.0715	1.0383	1.0608	1.1166	1.0936
Three Year Average				1.0719	1.0903

UNDERTAKING NO. JT1.5:

To clarify what is meant by “2009 Non-weather-normalized forecast values”

Response:

This query relates back to Interrogatory VECC-PC-28 in which there was a discrepancy between the distribution revenues forecasted in Exhibit 3 of the Application and those used for the disposition of account 1508 in Exhibit 5.

This discrepancy has its origins in the error, previously discussed and corrected, in which the rate design in the original application material improperly averaged 2008 and 2009 forecast values for rate determination. These rate designs were corrected in the Board Staff Interrogatories discussed in Undertaking JT2.1 and updated rate design models were filed with the Board on December 12, 2008.

Future calculation of regulatory asset disposition rate riders will be determined using the same weather normalized metrics as are the distribution rates.

UNDERTAKING NO. JT1.6:

To advise whether or not CNPI can prepay the promissory note

Response:

The question was whether CNPI can repay the $15,000,000 promissory note. The question was answered orally and can be found on pages 152 to 153 in the transcript. In summary, the answer is that although FortisOntario may demand repayment from CNPI, CNPI does not have the right to unilaterally repay prior to the end of the term of the note.

UNDERTAKING NO. JT1.7:

To clarify what percentage of the revenue requirement is to be recovered through fixed charge.

Response:

This question related to Exhibit 9, Tab 1, Schedule 1, page 16 of the Port Colborne application. At line 3, it stated that the Monthly Fixed Service Charge was being reallocated from 51.5% to 61.2% of the residential class revenue requirement.

This matter was addressed orally beginning in the middle of page 135 of the transcript, EB-2008-0222-0223-0224,April20Vol1. The reference in Exhibit 9, Tab 1, Schedule 1, page 1 was an editing error and should have read, in the application, “from 61.2% to 51.5%”.

UNDERTAKING NO. JT1.8:

To provide the number of servers replaced by CNPI for 2006 to 2008 and for forecast 2009

Response:

Server Replacement per Year – (2006 Actual to 2009 Test Year)

2006 Actual Year	**Cost ($)**	**Count (#)**
• SAP Application Server	$10,000	1
• SAP Development Server	$10,000	1
Total	**$20,000**	**2**
2007 Actual Year	**Cost ($)**	**Count (#)**
• SAP Production and DR (Disaster Recovery) Servers	$33,827	2
• Production EBT Server	$11,058	1
Total	**$44,885**	**3**
2008 Bridge Year	**Cost ($)**	**Count (#)**
• Production VPN Server	$15,000	1
• New Disaster Recovery SAP Application Server	$12,000	1
• Replacement SCADA Servers (Production and DR)	$20,000	2
Total	**$47,000**	**4**
2009 Test Year	**Cost ($)**	**Count (#)**
• Production/DR Email and File Servers	$50,000	4
• Replacement Utility Servers	$20,000	2
Total	**$70,000**	**6**

UNDERTAKING NO. JT1.9:

To update SAIDI, SAIFI and CAIDI numbers to include 2008 values.

Response:

This question pertained to 2008 reliability indices for Fort Erie. The table from OEB Interrogatory #16 is reproduced below, with 2008 indices added.

	All Causes of Interruptions			All Interruptions except for Loss of Supply (Cause Code 2)		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	15.15	4.26	3.56	15.15	4.26	3.56
2003	6.51	4.87	1.34	4.17	3.66	1.14
2004	4.90	2.92	1.68	4.90	2.92	1.68
2005	2.67	3.10	0.86	2.67	3.10	0.86
2006	61.87	12.54	4.94	61.68	12.06	5.11
2007	3.95	3.13	1.26	3.95	3.13	1.26
2008	**3.38**	**3.18**	**1.06**	**3.38**	**3.18**	**1.06**

UNDERTAKING NO. JT1.10:

To provide percentage of that remaining 80 percent is in that non-discretionary category and the dollar value that would be put on that.

Response:

This question pertained to distribution system capital programs for Fort Erie for the 2009 Test Year, for capital spending not listed in response to OEB Interrogatory # 4 (that is, projects below the materiality threshold). To assist the Board, CNPI has also provided information regarding the capital programs for the Port Colborne and Eastern Ontario Power (EOP) territories.

Board staff defined “Discretionary” in Note 3 of its interrogatory #4 as “the need is determined at the discretion of the Applicant and the program can be deferred”. It is important to note that just because a capital project can be deferred does not mean that a project should be deferred. For example, good utility practice requires preventative capital investment in certain circumstances. All preventative capital investments could fit within Board staff’s definition of “Discretionary” capital investment. Clearly, the deferral of prudent preventative capital investment would not be good utility practice.

There may be some confusion regarding Board staff’s categorization of “Discretionary” and “Non-Discretionary” capital expenditures. In responding to the Board’s Interrogatory #4 to categorise projects above the materiality threshold as “Non-Discretionary” or “Discretionary”, CNPI defined projects with priority “1” as “Non-Discretionary” and projects with priority “2” as “Discretionary”. These priority rankings were merely intended to reflect the relative priority of 2009 Test Year projects rather than to reflect the absolute criticality of the project. By labelling certain capital projects as “Discretionary” in accordance with Board staff’s definition, CNPI in no way is suggesting that those projects are not needed in the test year. All of the capital projects proposed by CNPI for the test year are needed and prudent. Although projects defined as “Discretionary” could be deferred, they should not be deferred because deferral would incur reliability risks, increase the risk of outages, increase safety risks and could lead to unnecessary additional costs. All in all, deferral of these projects would not amount to good utility practice.

For Fort Erie, in its response to Board Interrogatory #4 CNPI defined two projects as “Discretionary” – the voltage conversion of Ratio Bank 67RT4 and the replacement of underground feeder cables at Station 12. As described in the foregoing, these projects were assigned priority “2”. Both projects are prudent and necessary in Test Year 2009, and deferral would entail significant risks to safety and reliability. The voltage conversion of Ratio Bank 67RT4 is needed to carry on CNPI's voltage conversion program and implement a grounded-wye distribution system, the need for which was described extensively in the Application and subsequent interrogatories. Replacement of the underground cables at Station 12 is essential to upgrade aging plant and reduce the possibility of cable failures and consequent lengthy outages. Replacing aging facilities also reduces potential safety risks.

In terms of projects below the materiality threshold, in Fort Erie the estimated split between Non-Discretionary and Discretionary projects (as defined by Board staff) for Test Year 2009 is shown below:

Non-Discretionary projects:	$1,930,000 (82%)
Discretionary projects:	$ 420,000 (18%)

The more significant "Discretionary" projects below the materiality threshold include the following:

- Implementing the first phase of GIS, engineering analysis and outage management computer tools to improve the effectiveness of engineering, planning, and operational functions. CNPI does not presently have a Geographical Information System (GIS) to support planning and operations functions. CNPI currently has an outdated AutoCAD system for maintaining system maps, while information on field equipment (transformers, switches, etc) is kept in variety of different spreadsheets and databases. System planning functions such as load flow and short-circuit studies presently involve extensive manual calculations and analysis because CNPI does not have computerised tools to automate these processes. Adopting the computerised tools described above will greatly improve the efficiency and effectiveness of CNPI planning, engineering, and operations functions. Deferring this investment would result in continued inefficiencies in these functions.
- The purchase of a cargo van and two passenger cars to replace aging fleet vehicles that are increasingly costly to maintain. Deferring these purchases would result in the costly maintenance of aging and increasingly unreliable vehicles.
- The installation of an emergency generator at the Fort Erie service center to replace an aging, undersized unit. Improvements in CNPI's IT and UPS systems have increased the load that the backup generator needs to serve in an emergency. Deferring this project would result in CNPI incurring a significant risk of being unable to run its IT and

SCADA systems during an extended outage, which would adversely impact all business functions.

In Port Colborne, for 2009 Test Year projects above the materiality threshold the Killally Station feeder upgrading project was described as "Discretionary". As described in the foregoing, this project was classified as "Discretionary" because it had a priority ranking of 2. However, as described in the Application and subsequent Interrogatories this project is prudent and needed in 2009 Test Year to continue to upgrade the capacity of the Killally feeders and replace aging plant. Deferring this project would entail significant risks to safety and reliability because aging and undersized plant would continue to be maintained on the system.

For 2009 Test Year projects below the materiality threshold in Port Colborne, the split between "Non-Discretionary" and "Discretionary" projects is as follows:

Non-Discretionary projects:	$ 576,000 (97%)
Discretionary projects:	$ 20,000 (3%)

The most significant "Discretionary" project in Port Colborne is the continued expansion of the SCADA system to field devices to achieve remote monitoring and control of two reclosers and two loadbreak switches. This initiative will improve operational efficiency and outage response and also provide valuable real-time field data that would facilitate system planning and operations activities. Deferring this project would result in a lost opportunity to achieve operational and planning efficiencies and improve outage response because crews would have to continue to be dispatched to manually operate these devices and there would be no access to data.

In EOP, for 2009 Test Year projects above the materiality threshold the East Side Town Loop upgrade and the 4.16 kV feeder intertie projects were described as "Discretionary". As described in the foregoing, these projects were classified as "Discretionary" because they had priority rankings of 2. However, these projects are prudent and needed in 2009 Test Year to reduce risks to system reliability and replace aging plant. As described in the Application, the East Side Town Loop does not have the capacity to carry the Town load, a situation that would worsen as system load increases in future. With the status quo, the entire Town cannot be served from this section of line because of the undersized conductor on this loop. Deferring this project would incur a significant reliability risk because the entire Town could experience a lengthy outage because of this lack of capacity. Such a situation could occur if there were a catastrophic equipment failure at the Main Substation or if there was a broken pole along the West Side

Town Loop. The 4.16 kV feeder intertie project is necessary to increase transfer capability between the Herbert Street and Gananoque Stations. Deferring this project would entail the risk of significant numbers of customers experiencing lengthy outages because of the present lack of transfer capability. Such a situation could occur if, for example, the sole power transformer at the Herbert Street Substation was to fail or other catastrophic equipment failure occurs at that location.

For 2009 Test Year projects below the materiality threshold in EOP, the split between "Non-Discretionary" and "Discretionary" projects is as follows:

Non-Discretionary projects:	$ 343,000 (84%)
Discretionary projects:	$ 63,000 (16%)

The most significant "Discretionary" projects in EOP are Substation projects to decommission the old Thermal Plant Substation and implement SCADA at the new Main Substation. Deferring the Thermal Plant Substation decommissioning would increase potential safety hazards because aged, deteriorating equipment would remain in place and would continue to deteriorate. Implementing SCADA at the Main Substation would result in operational efficiency because devices could be remotely operated and crews would not have to be dispatched to operate equipment manually. Outage response would also improve because of access to real-time system information allied to the ability to remotely operate devices. Real-time system data would also be significant to undertaking accurate and effective system planning studies. Deferring this project, therefore, would result in a lost opportunity to gain operational and planning efficiency and improve outage response.

CNPI emphasizes that it would be a mistake to reduce its proposed capital expenditures based on the assumption that just because a capital expenditure can be deferred it should be deferred. As stated above, all of CNPI's proposed capital expenditures (both "discretionary" and "non-discretionary") are needed and prudent. Any deferrals would increase safety and reliability risks, and could result in increased costs in the future.

UNDERTAKING NO. JT1.11:

To provide 2008 update to Fort Erie Exhibit 3, Tab 3, Schedule 1, Page 1

Response:

Other Distribution Revenue Offset Table
FORT ERIE

OEB Account	Description	2006 EDR	2006 Actual	2007 Actual	2008 Actual	2009 Test Year
4080	Distribution Services Revenue (SSS Revenue)	39,657	38,731	37,828	37,498	40,000
4082	Retail Services Revenues	6,455	16,507	23,099	30,689	33,454
4084	Service Transaction Requests (STR) Revenues	80	1,543	1,514	1,081	1,500
4210	Rent from Electric Property	139,156	184,890	181,918	181,311	182,000
4220	Other Electric Revenues	19,343	55,534	2,647	3,700	3,000
4225	Late Payment Charges	55,797	120,224	187,841	201,539	188,000
4235	Miscellaneous Service Revenues	70,695	104,029	92,485	97,195	92,000
4325	Revenues from Merchandise, Jobbing, Etc.	1,695	108,708	127,868	149,368	-
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	26,808	(111,275)	(118,956)	(142,352)	-
4355	Gain on Disposition of Utility and Other Property	-	31,552	-	-	-
4360	Loss on Disposition of Utility and Other Property	(11,531)	-	(423)	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	22,684	(541)	(21,683)	-	-
4405	Interest and Dividend Income*	56,571	72,033	105,771	134,453	35,000
	Other Distribution Revenue Offset	**427,410**	**621,934**	**619,910**	**694,482**	**574,954**

* The average cash balance for the first quarter of 2008 and 2009 was $7.0 million and $1.2 million, respectively. The December 31, 2008 year end cash balance was $810,000.

Other Distribution Revenue Offset Table
PORT COLBORNE

OEB Account	Description	2006 EDR	2006 Actual	2007 Actual	2008 Actual	2009 Test Year
4080	Distribution Services Revenue	23,000	22,307	22,432	22,536	22,500
4082	Retail Services Revenues	4,488	11,533	13,955	18,838	22,500
4084	Service Transaction Requests (STR) Revenues	52	807	965	557	1,000
4210	Rent from Electric Property	88,715	90,598	85,818	85,941	86,000
4220	Other Electric Revenues	2,494	2,133	2,184	3,548	2,000
4225	Late Payment Charges	30,844	52,314	94,070	98,553	100,000
4235	Miscellaneous Service Revenues	175,479	177,812	174,855	173,514	52,000
4325	Revenues from Merchandise, Jobbing, Etc.	-	30,285	54,673	111,593	-
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	-	(29,325)	(60,792)	(103,751)	-
4390	Miscellaneous Non-Operating Income	-	524,646	-	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	-	-	(88)	-	-
4405	Interest and Dividend Income	127,157	-	-	-	-
	Other Distribution Revenue Offset Total	**452,228**	**883,110**	**388,072**	**411,329**	**286,000**

Other Distribution Revenue Offset Table
EOP

OEB Account	Description	2006 EDR	2006 Actual	2007 Actual	2008 Actual	2009 Test Year
4080	Distribution Services Revenue (SSS Revenue)	41,530	10,025	9,681	9,347	10,000
4082	Retail Services Revenues	-	1,195	2,981	4,630	3,096
4084	Service Transaction Requests (STR) Revenues	-	273	199	215	200
4210	Rent from Electric Property	63,839	52,368	48,665	49,003	49,000
4220	Other Electric Revenues	63,923	1,516	918	432	1,000
4225	Late Payment Charges	16,025	28,119	46,093	38,889	46,000
4235	Miscellaneous Service Revenues	9,458	21,706	26,620	23,014	27,000
4325	Revenues from Merchandise, Jobbing, Etc.	-	81,801	68,533	71,214	4,088
4330	Costs and Expenses of Merchandising, Jobbing, Etc.	1,530	(6,866)	(67,940)	(29,489)	(4,457)
4355	Gain on Disposition of Utility and Other Property	-	2,500	-	-	-
4360	Loss on Disposition of Utility and Other Property	28	-	4,198	-	-
4398	Foreign Exchange Gains and Losses, Including Amortization	(2)	-	-	-	-
4405	Interest and Dividend Income	(105,836)	-	-	-	-
	Other Distribution Revenue Offset Total	**90,495**	**192,636**	**139,947**	**167,255**	**135,927**

UNDERTAKING NO. JT1.12:

To clarify the different types of work

Response:

This question referred to the nature of works related to revenues for merchandise, jobbing, et cetera.

The response to this undertaking was provided orally, with discussion. The response begins at the bottom of page 149 and 150 of the transcript, EB-2008-0222-0223-0224,April20Vol1.

UNDERTAKING NO. JT1.13:

To explain why the significant increase between 2006 and 2007 and between 2007 and 2009

Response:

This question pertained to increases in vegetation management costs in Eastern Ontario Power between 2006 Actual and 2009 Test Year. Spending over the period is as follows:

- 2006 Actual: $41,209
- 2007 Actual: $74,319
- 2008 Bridge Year: $84,975
- 2009 Test Year: $86,343

Prior to 2007, vegetation management in Gananoque was carried out by EOP Line Crews. However, the crews did not have sufficient time to spend on vegetation management activities and the level of activity and spending in 2006 and years prior was insufficient to maintain adequate clearances across the distribution system. In 2007, the vegetation management budget was increased significantly and a qualified contractor was hired to perform these activities. This proved to be a more effective solution and commencing in 2008 EOP moved to the three-zone vegetation management system in place at other CNPI territories. It was recognised that increased tree trimming activity was required in rural areas, so there was an increase in spending from 2007 Actual to 2008 Bridge Year. Spending is forecast to remain fairly constant for 2009 Test Year, and in future years vegetation management expenditures are expected to remain fairly constant at about $85,000 annually.

UNDERTAKING JT1.14:

To provide 2008 target data

Response:

This question pertained to 2008 reliability indices for EOP. The table from OEB Interrogatory # 9 is reproduced below, with 2008 data added.

	All Causes of Interruptions			All Interruptions except for Loss of Supply (Cause Code 2)		
Year	SAIDI	SAIFI	CAIDI	SAIDI	SAIFI	CAIDI
2002	N/A	N/A	N/A	N/A	N/A	N/A
2003	9.22	3.06	3.01	3.16	1.10	2.87
2004	1.60	1.54	1.04	1.60	1.54	1.04
2005	4.07	1.05	3.89	4.07	1.05	3.89
2006	10.93	3.47	3.16	7.43	2.47	3.01
2007	10.13	5.78	1.75	5.18	3.82	1.36
2008	**0.85**	**0.55**	**1.55**	**0.85**	**0.55**	**1.55**

UNDERTAKING NO. JT2.1:

To clarify the response with respect to Board Staff Interrogatories No. 26, 28, 29, 31, 33, 38 and 40 in each of those interrogatories where CNPI states that it will refile its rate design model with revisions highlighted.

Response:

CNPI filed its responses to the initial interrogatories posed by Board Staff on December 12, 2008. In the covering letter provided with its responses, CNPI indicated that it was submitting electronic media on an accompanying CD. This CD contained the revised rate design models referenced above in EXCEL format.

Along with other information requested during the interrogatory phase, there were four EXCEL files contained in a folder on that CD entitled "Revised Models". Contained in that folder were the four EXCEL files referenced above; one each for CNPI – Fort Erie, CNPI – Port Colborne, CNPI – Gananoque and the Harmonized Applications of CNPI – Fort Erie and CNPI – Gananoque.

Specifically these were named:

CNPI-FE_DxDesign_20080815_R1

CNPI-PC_DxDesign_20080815_R1

CNPI-EOP_DxDesign_20080815_R1

CNPI-Harmonized_DxDesign_20080815_R1

UNDERTAKING NO. JT2.2:

To provide the quantum and impact on rates if the accounts were dispositioned

Response:

The quanta of the regulatory rate riders have been determined using the Regulatory Assets Recovery Model and the results are shown in the documents appendixed to this Undertaking.

The rate impacts have been determined using the rate design models filed on December 12, 2008 accompanying the Board Staff interrogatory responses. The following three tables display the respective rate impacts for each operating area as compared to the rate impacts determined by those rate design models filed on December 12, 2008.

CNPI - FORT ERIE 2009 EDR
Bill Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocation Informational Filing

Class	Consumption kWh	Consumption kW	Bill Impact %	Bill Impact with Regulatory Asset Recovery %
Residential	250		4.4%	4.8%
	500		4.8%	5.4%
Average Customer	671		4.8%	5.4%
	1,000		4.9%	5.5%
	1,250		4.9%	5.6%
	1,500		4.9%	5.6%
	2,000		4.9%	5.6%
General Service Less Than 50 kW	1,000		3.1%	3.8%
	2,000		3.0%	3.8%
Average Customer	2,657		3.0%	3.8%
	4,000		3.0%	3.8%
	6,000		3.0%	3.8%
	10,000		3.0%	3.8%
	15,000		3.0%	3.8%
General Service 50 to 4,999 kW	25,000	50	-0.4%	0.1%
	40,000	75	-0.5%	0.0%
	40,000	100	-0.5%	0.1%
Average Customer	83,747	226	-0.6%	0.1%
	125,000	250	-0.7%	-0.1%
	250,000	500	-0.7%	-0.1%
	1,500,000	2,500	-0.8%	-0.3%
Unmetered Scattered Load	200		9.7%	10.1%
Average Connection	245		9.6%	10.0%
	300		9.4%	9.9%
	500		9.2%	9.7%
	750		8.9%	9.5%
	900		8.7%	9.3%
	1,000		8.6%	9.2%
Sentinel Lighting	300	1	8.6%	9.5%
	900	3	9.3%	10.2%
	1,500	5	9.8%	10.6%
	3,000	10	9.8%	10.6%
	4,500	15	9.6%	10.5%
Street Lighting	3,000	10	8.7%	9.6%
	4,500	15	8.6%	9.5%
	6,000	20	8.6%	9.5%
	30,000	100	8.6%	9.4%
2873 Connections	172,000	491	9.9%	10.6%

CNPI - Port Colborne
Bill Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocation Informational Filing

Class	Consumption kWh	Consumption kW	Bill Impact %	Bill Impact with Regulatory Asset Recovery %
Residential	250		5.1%	6.1%
	500		6.4%	7.6%
Average Customer	664		6.8%	8.1%
	1,000		7.1%	8.5%
	1,250		7.2%	8.7%
	1,500		7.3%	8.8%
	2,000		7.4%	8.9%
General Service Less Than 50 kW	1,000		5.0%	6.4%
	2,000		5.7%	7.2%
Average Customer	2,305		5.8%	7.4%
	4,000		6.1%	7.7%
	6,000		6.2%	7.9%
	10,000		6.3%	8.1%
	15,000		6.4%	8.2%
General Service 50 to 4,999 kW	25,000	50	1.4%	2.2%
	40,000	100	1.9%	2.9%
	125,000	250	1.9%	2.9%
Average Customer	102,255	388	2.9%	4.5%
	250,000	500	2.0%	3.0%
	1,200,000	1,900	1.8%	2.6%
	2,500,000	4,000	1.8%	2.6%
Unmetered Scattered Load	250		9.3%	10.1%
	500		9.7%	10.8%
	600		9.8%	11.0%
	750		9.9%	11.2%
	1,500		9.8%	11.4%
Average Customer	2,549		9.8%	11.4%
Sentinel Lighting	300	1	8.1%	9.7%
	900	3	9.8%	11.4%
	1,500	5	9.9%	11.4%
	3,000	10	10.2%	11.7%
	4,500	15	10.3%	11.8%
Street Lighting	3,000	10	9.6%	11.4%
	4,500	15	9.6%	11.3%
	6,000	20	9.5%	11.3%
	30,000	100	9.5%	11.2%
1987 Connections	155,000	446	10.0%	11.4%

CNPI - Eastern Ontario Power
Bill Impacts May 2009 Compared To May 2008
Distribution Rates Calculated on the Basis of the Cost Allocation Informational Filing

Class	Consumption kWh	Consumption kW	Bill Impact %	Bill Impact with Regulatory Asset Recovery %
Residential	250		7.9%	8.5%
	500		9.7%	10.6%
Average Customer	791		10.4%	11.3%
	1,000		10.6%	11.6%
	1,250		10.8%	11.8%
	1,500		11.0%	11.9%
	2,000		11.1%	12.1%
General Service Less Than 50 kW	1,000		3.0%	3.8%
	2,000		3.1%	3.9%
Average Customer	2,807		3.1%	4.0%
	4,000		3.1%	4.0%
	6,000		3.1%	4.0%
	10,000		3.1%	4.0%
	15,000		3.1%	4.0%
General Service 50 to 4,999 kW	25,000	50	6.2%	6.7%
	40,000	75	6.5%	7.0%
Average Customer	44,320	139	10.3%	11.1%
	50,000	150	10.1%	10.9%
	75,000	175	8.6%	9.3%
	125,000	300	9.1%	9.9%
	250,000	500	8.1%	8.8%
Unmetered Scattered Load	250		3.1%	3.5%
	350		3.4%	3.9%
	600		3.8%	4.5%
	750		4.0%	4.7%
Average Customer	985		4.1%	4.8%
	1,000		4.1%	4.8%
Sentinel Lighting	300	1	9.1%	10.3%
	900	3	10.2%	11.4%
	1,500	5	10.1%	11.3%
	3,000	10	10.3%	11.4%
	4,500	15	10.3%	11.4%
Street Lighting	3,000	10	9.2%	10.3%
	4,500	15	9.1%	10.2%
	6,000	20	9.0%	10.1%
	30,000	100	9.0%	10.1%
557 Connections	46,000	129	10.1%	10.9%

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. EOP	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Account Description	Account Number	Principal Amounts as of Dec-31 2007	Interest to Dec31-07	Interest Jan-1 to Dec31-08	Interest Jan1-09 to Apr30-09				Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (249,816)	$ (21,066)	$ (9,943)	$ (1,738)				$ (282,563)
RSVA - One-time Wholesale Market Service	1582	$ -	$ -	$ -	$ -				$ -
RSVA - Retail Transmission Network Charge	1584	$ (129,500)	$ (23,694)	$ (5,154)	$ (901)				$ (159,249)
RSVA - Retail Transmission Connection Charge	1586	$ 6,000	$ (12,270)	$ 239	$ 42				$ (5,990)
RSVA - Power	1588	$ 566,154	$ 66,532	$ 22,533	$ 3,939				$ 659,159
Sub-Totals		$ 192,838	$ 9,502	$ 7,675	$ 1,342	$ -	$ -	$ -	$ 211,357
Other Regulatory Assets	1508	$ 10,497	$ 1,183	$ 418	$ 73				$ 12,171
Retail Cost Variance Account - Retail	1518	$ -	$ -	$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -	$ -	$ -	$ -				$ -
Misc. Deferred Debits - incl. Rebate Cheques	1525	$ -	$ -	$ -	$ -				$ -
Pre-Market Opening Energy Variances Total	1571								$ -
Extra-Ordinary Event Losses	1572	$ -	$ -	$ -	$ -				$ -
Deferred Rate Impact Amounts	1574								$ -
Other Deferred Credits	2425								$ -
Sub-Totals		$ 10,497	$ 1,183	$ 418	$ 73	$ -	$ -		$ 12,171
Totals per column		$ 203,335	$ 10,685	$ 8,093	$ 1,415	$ -	$ -	$ -	$ 223,528

	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009
Annual interest rate:	5.14%	4.08%	3.35%	3.35%	2.45%	1.00%
Monthly interest rate:	0.4283%	0.3400%	0.2792%	0.2792%	0.2042%	0.0833%

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. EOP	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

2009 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue
RESIDENTIAL CLASS		29,586,254	3,119	$ 1,096,151
GENERAL SERVICE <50 KW CLASS		14,048,011	417	$ 402,239
GENERAL SERVICE >50 KW NON TIME OF USE	58,180	18,614,527	35	$ 702,718
GENERAL SERVICE >50 KW TIME OF USE				
INTERMEDIATE CLASS				
LARGE USER CLASS				
SMALL SCATTERED LOADS		94,602	8	$ 4,940
SENTINEL LIGHTS	241	80,618	91	$ 4,141
STREET LIGHTING	1,662	555,619	599	$ 23,173
Totals	60,083	62,979,631	4,269	$ 2,233,362

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue	Cust. #'s w/ Rebate Cheques	kWhs for Non TOU Customers
RESIDENTIAL CLASS	0.0%	47.0%	73.1%	49.1%		47.46%
GENERAL SERVICE <50 KW CLASS	0.0%	22.3%	9.8%	18.0%		22.53%
GENERAL SERVICE >50 KW NON TIME OF USE	96.8%	29.6%	0.8%	31.5%		29.86%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%		
INTERMEDIATE CLASS	0.0%	0.0%	0.0%	0.0%		
LARGE USER CLASS	0.0%	0.0%	0.0%	0.0%		
SMALL SCATTERED LOADS	0.0%	0.2%	0.2%	0.2%		0.15%
SENTINEL LIGHTS	0.4%	0.1%	2.1%	0.2%		
STREET LIGHTING	2.8%	0.9%	14.0%	1.0%		
Totals	100%	100%	100%	100%	0%	100%

Sheet 2 - Rate Riders Calculation

NAME OF UTILITY	Canadian Niagara Power Inc. EOP	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Regulatory Asset Accounts:	**Amount**	**ALLOCATOR**	**Residential**	**GS < 50 KW**	**GS > 50 Non TOU**	**GS > 50 TOU**	**Intermediate**	**Large Users**	**Small Scattered Load**	**Sentinel Lighting**	**Street Lighting**	**Total**
WMSC - Account 1580	$ (282,563)	kWh	$ (132,741)	$ (63,028)	$ (83,516)	$ -	$ -	$ -	$ (424)	$ (362)	$ (2,493)	$ (282,563)
One-Time WMSC - Account 1582	$ -	kWh	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Network - Account 1584	$ (159,249)	kWh	$ (74,811)	$ (35,521)	$ (47,068)	$ -	$ -	$ -	$ (239)	$ (204)	$ (1,405)	$ (159,249)
Connection - Account 1586	$ (5,990)	kWh	$ (2,814)	$ (1,336)	$ (1,770)	$ -	$ -	$ -	$ (9)	$ (8)	$ (53)	$ (5,990)
Power - Account 1588	$ 659,159	kWh	$ 309,656	$ 147,030	$ 194,824	$ -	$ -	$ -	$ 990	$ 844	$ 5,815	$ 659,159
Subtotal - RSVA	$ 211,357		$ 99,290	$ 47,145	$ 62,470	$ -	$ -	$ -	$ 317	$ 271	$ 1,865	$ 211,357
Other Regulatory Assets - Account 1508	$ 12,171	Dx Revenue	$ 5,974	$ 2,192	$ 3,830	$ -	$ -	$ -	$ 27	$ 23	$ 126	$ 12,171
Retail Cost Variance Account - Acct 1518	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account (STR) Acct 1548	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rebate Cheques - Acct 1525	$ -	# cust. w/ Rebate Cheq										$ -
Hydro One's Environmental Costs - Acct 1525	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pre Market Opening Energy - Acct 1571	$ -	kWh for Non TOU Cust.	$ -	$ -	$ -				$ -			$ -
Extraordinary Event Losses - Acct 1572	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts - Acct 1574	$ -											$ -
Other Deferred Credits - Acct 2425	$ -											$ -
Transition Costs - Acct 1570	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA	$ 12,171		$ 5,974	$ 2,192	$ 3,830	$ -	$ -	$ -	$ 27	$ 23	$ 126	$ 12,171
[illegible] to be Recovered	$ 223,528		$ 105,264	$ 49,337	$ 66,299	$ -	$ -	$ -	$ 344	$ 293	$ 1,991	$ 223,528
Balance to be collected or refunded in the next 3 years	$ 223,528		$ 105,264	$ 49,337	$ 66,299	$ -	$ -	$ -	$ 344	$ 293	$ 1,991	$ 223,528
Balance to be collected or refunded per year	$ 74,509		$ 35,088	$ 16,446	$ 22,100	$ -	$ -	$ -	$ 115	$ 98	$ 664	$ 74,509

Class	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Intermediate	Large Users	Scattered Load	Sentinel Lighting	Street Lighting
Regulatory Asset Rate Riders	$ 0.0012	$ 0.0012	$ 0.3799				$ 0.0012	$ 0.4054	$ 0.3993
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh	kW	kW

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. Fort Erie	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Account Description	Account Number	Principal Amounts as of Dec-31 2007	Interest to Dec31-07	Interest Jan-1 to Dec31-08	Interest Jan1-09 to Apr30-09				Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (569,936)	$ 4,926	$ (22,683)	$ (3,966)				$ (591,659)
RSVA - One-time Wholesale Market Service	1582	$ 34,632	$ 5,613	$ 1,378	$ 241				$ 41,864
RSVA - Retail Transmission Network Charge	1584	$ 148,764	$ (56,926)	$ 5,921	$ 1,035				$ 98,795
RSVA - Retail Transmission Connection Charge	1586	$ 152,782	$ (62,480)	$ 6,081	$ 1,063				$ 97,446
RSVA - Power	1588	$ 879,925	$ 187,218	$ 35,021	$ 6,123				$ 1,108,288
Sub-Totals		$ 646,168	$ 78,351	$ 25,717	$ 4,496	$ -	$ -	$ -	$ 754,733
Other Regulatory Assets	1508	$ 37,089	$ 4,181	$ 1,476	$ 258				$ 43,004
Retail Cost Variance Account - Retail	1518	$ -	$ -	$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -	$ -	$ -	$ -				$ -
Misc. Deferred Debits - incl. Rebate Cheques	1525	$ -	$ -	$ -	$ -				$ -
Pre-Market Opening Energy Variances Total	1571								$ -
Extra-Ordinary Event Losses	1572	$ -	$ -	$ -	$ -				$ -
Deferred Rate Impact Amounts	1574								$ -
Other Deferred Credits	2425								$ -
Sub-Totals		$ 37,089	$ 4,181	$ 1,476	$ 258	$ -	$ -		$ 43,004
Totals per column		$ 683,257	$ 82,532	$ 27,194	$ 4,754	$ -	$ -	$ -	$ 797,737

	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009
Annual interest rate:	5.14%	4.08%	3.35%	3.35%	2.45%	1.00%
Monthly interest rate:	0.4283%	0.3400%	0.2792%	0.2792%	0.2042%	0.0833%

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. Fort Erie	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

2009 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue
RESIDENTIAL CLASS		115,322,011	14,315	$ 4,905,424
GENERAL SERVICE <50 KW CLASS		37,747,136	1,184	$ 1,229,522
GENERAL SERVICE >50 KW NON TIME OF USE	399,198	147,729,800	147	$ 3,078,408
GENERAL SERVICE >50 KW TIME OF USE				
INTERMEDIATE CLASS				
LARGE USER CLASS				
SMALL SCATTERED LOADS		349,768	119	$ 24,345
SENTINEL LIGHTS	2,423	797,374	961	$ 42,011
STREET LIGHTING	6,718	2,210,842	3,095	$ 84,885
Totals	408,339	304,156,931	19,821	$ 9,364,595

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue	Cust. #'s w/ Rebate Cheques	kWhs for Non TOU Customers
RESIDENTIAL CLASS	0.0%	37.9%	72.2%	52.4%		38.29%
GENERAL SERVICE <50 KW CLASS	0.0%	12.4%	6.0%	13.1%		12.53%
GENERAL SERVICE >50 KW NON TIME OF USE	97.8%	48.6%	0.7%	32.9%		49.06%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%		
INTERMEDIATE CLASS	0.0%	0.0%	0.0%	0.0%		
LARGE USER CLASS	0.0%	0.0%	0.0%	0.0%		
SMALL SCATTERED LOADS	0.0%	0.1%	0.6%	0.3%		0.12%
SENTINEL LIGHTS	0.6%	0.3%	4.8%	0.4%		
STREET LIGHTING	1.6%	0.7%	15.6%	0.9%		
Totals	100%	100%	100%	100%	0%	100%

Sheet 2 - Rate Riders Calculation

NAME OF UTILITY	Canadian Niagara Power Inc. Fort Erie	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Regulatory Asset Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Intermediate	Large Users	Small Scattered Load	Sentinel Lighting	Street Lighting	Total
WMSC - Account 1580	$ (591,659)	kWh	$ (224,329)	$ (73,427)	$ (287,370)	$ -	$ -	$ -	$ (680)	$ (1,551)	$ (4,301)	$ (591,659)
One-Time WMSC - Account 1582	$ 41,864	kWh	$ 15,873	$ 5,195	$ 20,333	$ -	$ -	$ -	$ 48	$ 110	$ 304	$ 41,864
Network - Account 1584	$ 98,795	kWh	$ 37,458	$ 12,261	$ 47,985	$ -	$ -	$ -	$ 114	$ 259	$ 718	$ 98,795
Connection - Account 1586	$ 97,446	kWh	$ 36,947	$ 12,093	$ 47,330	$ -	$ -	$ -	$ 112	$ 255	$ 708	$ 97,446
Power - Account 1588	$ 1,108,288	kWh	$ 420,211	$ 137,543	$ 538,298	$ -	$ -	$ -	$ 1,274	$ 2,905	$ 8,056	$ 1,108,288
Subtotal - RSVA	$ 754,733		$ 286,159	$ 93,665	$ 366,576	$ -	$ -	$ -	$ 868	$ 1,979	$ 5,486	$ 754,733
Other Regulatory Assets - Account 1508	$ 43,004	Dx Revenue	$ 22,527	$ 5,646	$ 14,137	$ -	$ -	$ -	$ 112	$ 193	$ 390	$ 43,004
Retail Cost Variance Account - Acct 1518	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account (STR) Acct 1548	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rebate Cheques - Acct 1525	$ -	# cust. w/ Rebate Cheq										$ -
Hydro One's Environmental Costs - Acct 1525	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pre Market Opening Energy - Acct 1571	$ -	kWh for Non TOU Cust.	$ -	$ -	$ -				$ -			$ -
Extraordinary Event Losses - Acct 1572	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts - Acct 1574	$ -											$ -
Other Deferred Credits - Acct 2425	$ -											$ -
Transition Costs - Acct 1570	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA	$ 43,004		$ 22,527	$ 5,646	$ 14,137	$ -	$ -	$ -	$ 112	$ 193	$ 390	$ 43,004
[illegible]o be Recovered	$ 797,737		$ 308,686	$ 99,312	$ 380,712	$ -	$ -	$ -	$ 980	$ 2,172	$ 5,876	$ 797,737
Balance to be collected or refunded in the next 3 years	$ 797,737		$ 308,686	$ 99,312	$ 380,712	$ -	$ -	$ -	$ 980	$ 2,172	$ 5,876	$ 797,737
Balance to be collected or refunded per year	$ 265,912		$ 102,895	$ 33,104	$ 126,904	$ -	$ -	$ -	$ 327	$ 724	$ 1,959	$ 265,912

Class	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Intermediate	Large Users	Scattered Load	Sentinel Lighting	Street Lighting
Regulatory Asset Rate Riders	$ 0.0009	$ 0.0009	$ 0.3179				$ 0.0009	$ 0.2987	$ 0.2915
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh	kW	kW

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. Port Colborne	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Account Description	Account Number	Principal Amounts as of Dec-31 2007	Interest to Dec31-07	Interest Jan-1 to Dec31-08	Interest Jan1-09 to Apr30-09				Total Claim
RSVA - Wholesale Market Service Charge	1580	$ (367,336)	$ 1,149	$ (14,620)	$ (2,556)				$ (383,363)
RSVA - One-time Wholesale Market Service	1582	$ 23,520	$ 2,765	$ 936	$ 164				$ 27,385
RSVA - Retail Transmission Network Charge	1584	$ (184,446)	$ (57,394)	$ (7,341)	$ (1,283)				$ (250,463)
RSVA - Retail Transmission Connection Charge	1586	$ 111,109	$ (33,309)	$ 4,422	$ 773				$ 82,995
RSVA - Power	1588	$ 1,338,096	$ 124,246	$ 53,256	$ 9,311				$ 1,524,908
Sub-Totals		$ 920,942	$ 37,458	$ 36,654	$ 6,408	$ -	$ -	$ -	$ 1,001,462
Other Regulatory Assets	1508	$ 22,393	$ 2,525	$ 891	$ 156				$ 25,965
Retail Cost Variance Account - Retail	1518	$ -	$ -	$ -	$ -				$ -
Retail Cost Variance Account - STR	1548	$ -	$ -	$ -	$ -				$ -
Misc. Deferred Debits - incl. Rebate Cheques	1525	$ -	$ -	$ -	$ -				$ -
Pre-Market Opening Energy Variances Total	1571								$ -
Extra-Ordinary Event Losses	1572	$ -	$ -	$ -	$ -				$ -
Deferred Rate Impact Amounts	1574								$ -
Other Deferred Credits	2425								$ -
Sub-Totals		$ 22,393	$ 2,525	$ 891	$ 156	$ -	$ -		$ 25,965
Totals per column		$ 943,336	$ 39,982	$ 37,545	$ 6,564	$ -	$ -	$ -	$ 1,027,426

	Q1 2008	Q2 2008	Q3 2008	Q4 2008	Q1 2009	Q2 2009
Annual interest rate:	5.14%	4.08%	3.35%	3.35%	2.45%	1.00%
Monthly interest rate:	0.4283%	0.3400%	0.2792%	0.2792%	0.2042%	0.0833%

SHEET 1 - December 31, 2007 Regulatory Assets

NAME OF UTILITY	Canadian Niagara Power Inc. Port Colborne	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

2009 Data By Class	kW	kWhs	Cust. Num.'s	Dx Revenue
RESIDENTIAL CLASS		64,972,406	8,155	$ 3,146,105
GENERAL SERVICE <50 KW CLASS		25,831,151	934	$ 761,214
GENERAL SERVICE >50 KW NON TIME OF USE	377,959	99,392,250	81	$ 1,826,739
GENERAL SERVICE >50 KW TIME OF USE				
INTERMEDIATE CLASS				
LARGE USER CLASS				
SMALL SCATTERED LOADS		581,173	19	$ 18,818
SENTINEL LIGHTS	38	12,725	36	$ 2,102
STREET LIGHTING	5,433	1,792,552	1,985	$ 70,896
Totals	383,430	192,582,257	11,210	$ 5,825,874

Allocators	kW	kWhs	Cust. Num.'s	Dx Revenue	Cust. #'s w/ Rebate Cheques	kWhs for Non TOU Customers
RESIDENTIAL CLASS	0.0%	33.7%	72.7%	54.0%		34.06%
GENERAL SERVICE <50 KW CLASS	0.0%	13.4%	8.3%	13.1%		13.54%
GENERAL SERVICE >50 KW NON TIME OF USE	98.6%	51.6%	0.7%	31.4%		52.10%
GENERAL SERVICE >50 KW TIME OF USE	0.0%	0.0%	0.0%	0.0%		
INTERMEDIATE CLASS	0.0%	0.0%	0.0%	0.0%		
LARGE USER CLASS	0.0%	0.0%	0.0%	0.0%		
SMALL SCATTERED LOADS	0.0%	0.3%	0.2%	0.3%		0.30%
SENTINEL LIGHTS	0.0%	0.0%	0.3%	0.0%		
STREET LIGHTING	1.4%	0.9%	17.7%	1.2%		
Totals	100%	100%	100%	100%	0%	100%

Sheet 2 - Rate Riders Calculation

NAME OF UTILITY	Canadian Niagara Power Inc. Port Colborne	**LICENCE NUMBER**	
NAME OF CONTACT	Doug Bradbury	**DOCID NUMBER**	
E-mail Address	doug.bradbury@cnpower.com		
VERSION NUMBER		**PHONE NUMBER**	905-994-3634
Date		**(extension)**	

Regulatory Asset Accounts:	Amount	ALLOCATOR	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Intermediate	Large Users	Small Scattered Load	Sentinel Lighting	Street Lighting	Total
WMSC - Account 1580	$ (383,363)	kWh	$ (129,337)	$ (51,421)	$ (197,855)	$ -	$ -	$ -	$ (1,157)	$ (25)	$ (3,568)	$ (383,363)
One-Time WMSC - Account 1582	$ 27,385	kWh	$ 9,239	$ 3,673	$ 14,134	$ -	$ -	$ -	$ 83	$ 2	$ 255	$ 27,385
Network - Account 1584	$ (250,463)	kWh	$ (84,500)	$ (33,595)	$ (129,265)	$ -	$ -	$ -	$ (756)	$ (17)	$ (2,331)	$ (250,463)
Connection - Account 1586	$ 82,995	kWh	$ 28,000	$ 11,132	$ 42,834	$ -	$ -	$ -	$ 250	$ 5	$ 773	$ 82,995
Power - Account 1588	$ 1,524,908	kWh	$ 514,466	$ 204,537	$ 787,010	$ -	$ -	$ -	$ 4,602	$ 101	$ 14,194	$ 1,524,908
Subtotal - RSVA	$ 1,001,462		$ 337,868	$ 134,327	$ 516,857	$ -	$ -	$ -	$ 3,022	$ 66	$ 9,322	$ 1,001,462
Other Regulatory Assets - Account 1508	$ 25,965	Dx Revenue	$ 14,022	$ 3,393	$ 8,141	$ -	$ -	$ -	$ 84	$ 9	$ 316	$ 25,965
Retail Cost Variance Account - Acct 1518	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Retail Cost Variance Account (STR) Acct 1548	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Rebate Cheques - Acct 1525	$ -	# cust. w/ Rebate Cheq										$ -
Hydro One's Environmental Costs - Acct 1525	$ -	Dx Revenue	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Pre Market Opening Energy - Acct 1571	$ -	kWh for Non TOU Cust.	$ -	$ -	$ -				$ -			$ -
Extraordinary Event Losses - Acct 1572	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Deferred Rate Impact Amounts - Acct 1574	$ -											$ -
Other Deferred Credits - Acct 2425	$ -											$ -
Transition Costs - Acct 1570	$ -	# of Customers	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -	$ -
Subtotal - Non RSVA	$ 25,965		$ 14,022	$ 3,393	$ 8,141	$ -	$ -	$ -	$ 84	$ 9	$ 316	$ 25,965
[illegible]o be Recovered	$ 1,027,426		$ 351,890	$ 137,719	$ 524,999	$ -	$ -	$ -	$ 3,106	$ 76	$ 9,638	$ 1,027,426
Balance to be collected or refunded in the next 3 years	$ 1,027,426		$ 351,890	$ 137,719	$ 524,999	$ -	$ -	$ -	$ 3,106	$ 76	$ 9,638	$ 1,027,426
Balance to be collected or refunded per year	$ 342,475		$ 117,297	$ 45,906	$ 175,000	$ -	$ -	$ -	$ 1,035	$ 25	$ 3,213	$ 342,475

Class	Residential	GS < 50 KW	GS > 50 Non TOU	GS > 50 TOU	Intermediate	Large Users	Scattered Load	Sentinel Lighting	Street Lighting
Regulatory Asset Rate Riders	$ 0.0018	$ 0.0018	$ 0.4630				$ 0.0018	$ 0.6626	$ 0.5913
Billing Determinants	kWh	kWh	kW	kW	kW	kW	kWh	kW	kW

UNDERTAKING NO. JT2.3:

To provide the impact on moving the Revenue to Cost Ratio from existing to 50% closer to the range.

Response:

CNPI was asked to determine customer class bill impacts as a result of moving certain customer class revenue to cost ratios that were not within the Board's guidelines to at least 50% of the spread between the 2006 cost allocation result and the lower bound of this guideline.

CNPI has complied with this request and the results are shown below in tabular format.

CNPI – Fort Erie Rate Design
Moving Certain Customer Classes 50% of Spread to Lower Bound of Range

Customer Class	Revenue to Cost Ratio from 2006 Cost Allocation %	Board's Range Guideline %	Proposed Revenue to Cost Ratio %	50% Target %	Rate Impact Range %
Residential	82.69	85 – 115	86.46	N/A	4.4 – 4.9
GS < 50 kW	129.81	80 – 120	119.74	N/A	3.0 – 3.1
GS > 50 kW	151.44	80 – 180	143.59	N/A	(0.9) – (1.2)
Street Lights	19.16	70 – 120	23.39	44.58	29.1 – 41.5
Sentinel Lights	37.35	70 – 120	53.09	53.68	8.8 – 10.1
USL	56.76	80 - 120	56.35	68.38	16.6 – 21.4

For the CNPI – Fort Erie, the additional revenue requirement needed to increase the customer class's identified was taken from the GS > 50 kW customer class thus reducing its revenue to cost ratio.

CNPI – Port Colborne Rate Design
Moving Certain Customer Classes 50% of Spread to Lower Bound of Range

Customer Class	Revenue to Cost Ratio from 2006 Cost Allocation %	Board's Range Guideline %	Proposed Revenue to Cost Ratio %	50% Target %	Rate Impact Range %
Residential	93.42	85 – 115	93.43	N/A	5.1 – 7.4
GS < 50 kW	89.36	80 – 120	89.39	N/A	5.0 – 6.4
GS > 50 kW	167.08	80 – 180	135.58	N/A	1.0 – 2.7
Street Lights	29.39	70 – 120	38.69	49.70	17.0 – 19.6
Sentinel Lights	49.58	70 – 120	63.46	N/A	8.1 – 10.3
USL	61.43	80 - 120	52.51	70.72	20.5 – 35.0

For the CNPI – Port Colborne, the additional revenue requirement needed to increase the customer class's identified was taken from the GS > 50 kW customer class thus reducing its revenue to cost ratio.

CNPI – Gananoque Rate Design
Moving Certain Customer Classes 50% of Spread to Lower Bound of Range

Customer Class	Revenue to Cost Ratio from 2006 Cost Allocation %	Board's Range Guideline %	Proposed Revenue to Cost Ratio %	50% Target %	Rate Impact Range %
Residential	73.02	85 – 115	80.04	N/A	7.9 – 11.1
GS < 50 kW	142.48	80 – 120	127.99	N/A	2.8 – 3.0
GS > 50 kW	158.23	80 – 180	145.03	N/A	6.2 – 10.3
Street Lights	27.64	70 – 120	44.43	48.82	11.5 – 13.5
Sentinel Lights	31.77	70 – 120	74.94	N/A	9.1 – 10.3
USL	65.94	80 - 120	99.81	N/A	3.1 – 4.1

For the CNPI – Gananoque, the additional revenue requirement needed to increase the customer class's identified was taken from the GS < 50 kW customer class thus reducing its revenue to cost ratio.

CNPI – Harmonized Rate Design Fort Erie & Gananoque Moving Certain Customer Classes 50% of Spread to Lower Bound of Range					
Customer Class	Revenue to Cost Ratio from 2006 Cost Allocation %	Board's Range Guideline %	Proposed Revenue to Cost Ratio %	50% Target %	Rate Impact Range %
Residential	80.52	85 – 115	82.88	N/A	(0.7) – 10.8
GS < 50 kW	133.51	80 – 120	120.00	N/A	(1.9) – 8.1
GS > 50 kW	154.80	80 – 180	152.66	N/A	(12.1) – 8.0
Street Lights	19.51	70 – 120	23.91	44.76	20.1 – 40.2
Sentinel Lights	37.46	70 – 120	54.61	N/A	0.7 – 9.0
USL	57.76	80 - 120	44.69	68.80	33.3 – 173.0

For the CNPI – Harmonized, the additional revenue requirement needed to increase the customer class's identified was taken from the GS > 50 kW customer class thus reducing its revenue to cost ratio.

The significant impact for the Unmetered Scattered Load customer class is in Fort Erie has been discussed in the application and will be mitigated by changing the customer billing format from a per connection basis to a per customer basis.

UNDERTAKING NO. JT2.4:

To calculate the rate impact on the Fort Erie residential customer as a result of the rate harmonization proposal Fort Erie, Gananoque, and Eastern Ontario Power and calculate customer impacts based on class average consumption and using 1000-kilowatt-hours.

Response:

Using the most recent rate design information provided in response to Board staff interrogatories on December 12, 2008, CNPI has calculated the total bill impacts of the rate harmonization proposal as compared to the rates proposed in the individual applications.

The results are shown in tabular form below:

Comparison of Fort Erie Rate Proposal and Fort Erie Harmonized Rate Proposal

Class	Consumption kWh	Consumption kW	Proposed Stand Alone Bill 2009 Bill	Proposed Harmonized Bill 2009 Bill	Difference $	Bill Impact %
Residential						
Average Customer	671		$ 84.31	$ 83.31	$ (1.00)	-1.2%
	1,000		$ 116.51	$ 116.48	$ (0.03)	0.0%

Comparison of EOP Rate Proposal and EOP Harmonized Rate Proposal

Class	Consumption kWh	Consumption kW	Proposed Stand Alone Bill 2009 Bill	Proposed Harmonized Bill 2009 Bill	Difference $	Bill Impact %
Residential						
Average Customer	791		$ 99.58	$ 99.75	$ 0.17	0.2%
	1,000		$ 122.73	$ 122.55	$ (0.18)	-0.1%

UNDERTAKING NO. JT2.5:

To provide details as to the discrepancy in the decrease in the two figures.

Response:

The question is concerning the CNPI-EOP low voltage number of $107,300 versus $64,299. The $64,299 is the variance in account 5665 from 2006 Board Approved to 2006 Actual. The variance is explained as a reduction in low voltage of $107,300 offset by an increase in other miscellaneous expenses of $43,000.

UNDERTAKING NO. JT2.6:

To provide the timing assumption and number of the promissory note, and to clarify the amount and what time was assumed by way of the issuance.

Response

CNPI currently has outstanding a $15 million demand promissory note payable to FortisOntario. The company is forecasting an additional $6 million of affiliated borrowing in 2009. The total affiliated debt at the end of 2009 is forecast to be $21 million as set out at Exhibit 6 Tab 1 Schedule 1 of the pre-filed evidence.

CNPI forecasts regular borrowing requirements throughout the year to support the capital program including smart meters. For example, as of March 31, 2009 CNPI has approximately $1.9 million in amounts due to related parties primarily FortisOntario. It is anticipated that CNPI will replace the existing $15 million demand promissory note with a $21 million demand promissory note in the fourth quarter of 2009.

The 2008 $15 million promissory note bears a debt rate of 6.13%, which was set by FortisOntario to match the Board's deemed long-term debt rate. It is expected that for the new $21 million demand promissory note to be issued in 2009, FortisOntario will again apply a debt rate that matches the Board's deemed long-term debt rate, being 7.62%. Similar to the existing $15 million promissory note, the new $21 million promissory note will be both: (i) "affiliate debt that is callable on demand" [1]; and (ii) new affiliated debt with a contracted rate that is the same as the deemed long-term debt rate,[2] the debt rate of 7.62% should apply.

---

[1] Report of the Board on Cost of Capital and 2nd Generation Incentive Regulation for Ontario's Electricity Distributors (the "Cost of Capital Report"), first paragraph on page 14.
[2] Cost of Capital Report, last paragraph on page 13 requires the lower of the contracted rate and the deemed long-term debt rate for new affiliated debt.

UNDERTAKING NO. JT3.1:

To assess unusual costs in 2007 related to early retirement and apply it to the three utilities.

Response:

The 2007 early retirement window costs are as follows;

- CNPI-Fort Erie $367,698,
- CNPI-Port Colborne $100,000, and
- CNPI-EOP $15,300.

UNDERTAKING NO. JT3.2:

To reconcile $314,000.

Response

The questions relates to the reconciliation of the 2009 total combined OM&A expenses of $8,238,854 (SEC #2 Attachment A) and the total operating budget approved by CNPI's Board of Directors of $7,925,000 (i.e. total 2009 operating expenses of $8,160,000 less municipal and other taxes of $235,000) (SEC #5 Attachment B).

The CNPI combined amounts for OM&A of $8,238,854 and the CNPI Board Approved of $7,925,000 (net of municipal and other taxes) are reconcilable. The difference is due to non-recoverable STI's and the differing asset allocation methodologies. In the 2009 EDR, common assets and related depreciation are allocated to each operating unit. In the CNPI Board Approved, the assets and related depreciation are not allocated, instead a depreciation and cost of capital charge is applied. In order to compare the amounts the OM&A and depreciation expense need to be combined, see below.

Combined OM&A from IRR SEC # 2	8,239	
Combined Depreciation from IRR SEC # 2	3,114	11,353
Combined OM&A from CNPI Board Approved IRR SEC# 5	8,160	
Less Municipal and other taxes	235	
	7,925	
CNPI Board Approved depreciation expense	3,473	11,398
Variance		(45)
Non-recoverable STIs included in CNPI Board Approved operating expense		49
Difference due to rounding		4

Upon doing so, it is apparent that the combined OM&A budget approved by CNPI's Board of Directors is consistent with the combined OM&A proposed in the applications.

UNDERTAKING NO. JT3.3:

To provide the number for which recovery is being requested.

Response:

The question is regarding the amount of the cost of the lease being requested in the rate application as compared to the amount referenced in the supplementary evidence provided during the hearing. The amount in evidence and being requested in the 2008 bridge year and the 2009 test year is $1,528,200. The amount shown in the supplementary evidence related to OM&A comparators and provided during the hearing is $1,462,000. The latter amount is the $1,528,200 in evidence net of commodity taxes and deferred transaction charges.